APPENDIX D:

POEMS DOCUMENTATION

ONLOC-98-03

Policy Office
Electricity Modeling System (POEMS)
Model Documentation

In support of the Department of Energy's
Comprehensive Electricity Competition Plan

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Introduction

This paper documents POEMS, which integrates the Energy Information Administration's National Energy Modeling System (NEMS) with the more detailed electricity market model, TRADELEC™, developed by OnLocation, Inc.

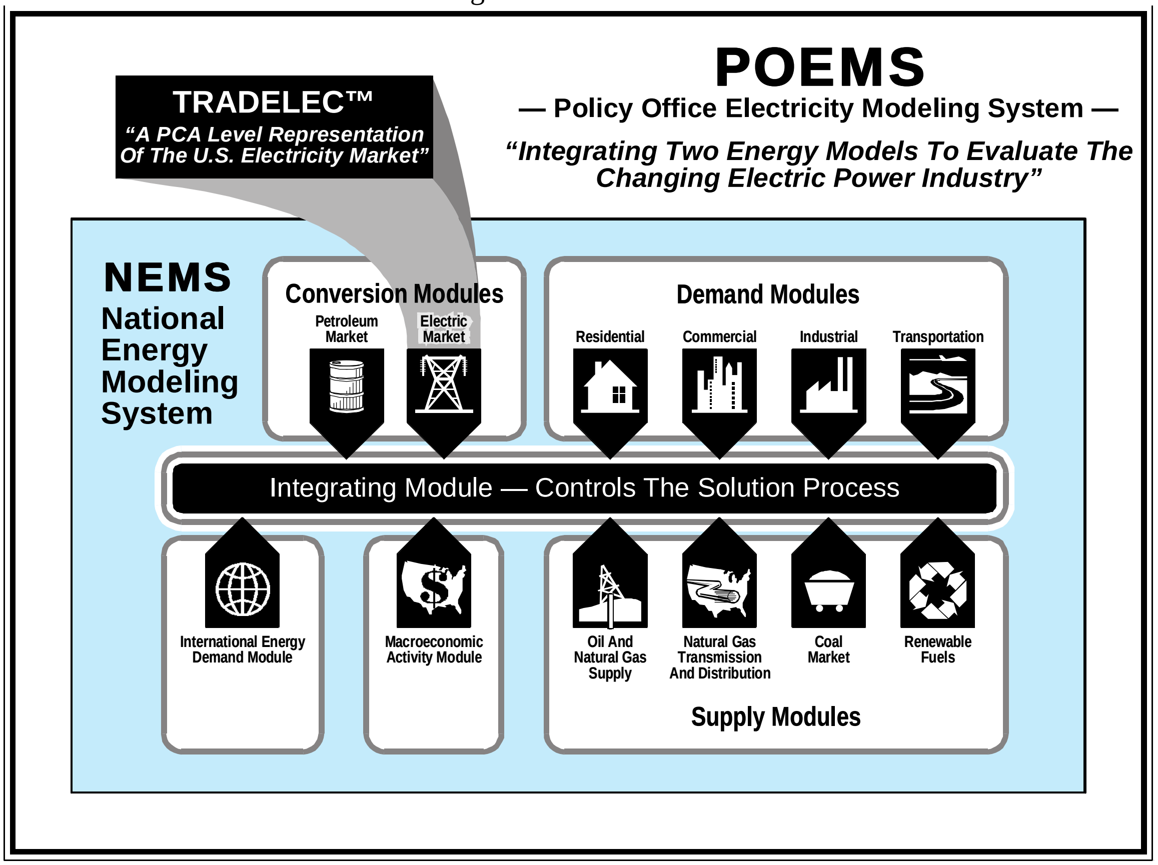
POEMS

POEMS is a system that integrates two existing models, the Energy Information Administration's (EIA) National Energy Modeling System (NEMS) and TRADELEC™, a detailed competitive electricity market model addressing alternative market (i.e., pricing) mechanisms ranging from traditional cost-of-service rate regulation, performance-based rate-setting, and market rates; including the impact of increased trading of electricity, associated network power flows, and resulting capacity utilization (dispatch).

NEMS is an energy-economy modeling system of U.S. energy markets. NEMS provides projections of the production, imports, conversion, consumption, and prices of energy subject to assumptions regarding macroeconomic and financial factors, world energy markets, resource availability and costs, behavioral and technological cost criteria, cost and performance characteristics of energy technologies, and demographics. NEMS is used to develop the baseline energy forecasts published annually by EIA in the Annual Energy Outlook. It can also be used as a tool for energy policy analysis related to existing and proposed changes in a wide variety of laws and regulations related to energy production and use, environmental protection, environmental requirements, or tax provisions. Documentation of NEMS is available from EIA.

NEMS is modular in structure. (See Figure 1) On the supply side, there are separate modules for oil and gas supply, gas transmission, coal markets, and renewable fuels. On the demand side, each end-use sector (residential, commercial, industrial, and transportation) is represented, with inter-fuel competition to meet end-use demands as appropriate. The electricity supply and distribution and petroleum refining sectors are classified as conversion modules. An integrating module interacts with all three categories of modules described above, together with modules representing the macro-economy and international energy markets. The integrating module controls the solution process, iterating the individual models until convergence representing equilibrium in the producing and consuming sectors is achieved.

Figure 1: Overview of POEMS



The design requirement to run all of the modules to equilibrium together constrains the level of detail provided in each NEMS module. While recognizing the advantages of the NEMS system, POEMS is more narrowly aimed at addressing questions surrounding electricity markets. For this purpose, there are significant advantages to a more disaggregated representation of the electricity sector. The approach taken in POEMS is to substitute TRADELEC™ for the electricity market module (EMM) in NEMS. Depending on the focus of the analysis, TRADELEC™ is run in conjunction with a relevant subset of NEMS modules, such as the various demand modules and the natural gas modules.

TRADELEC ™

Because of the importance of the electric power industry to the US economy and the engineering relationships that exist for the processes that convert primary fuels to electricity, detailed models of the power industry have long been used to help focus operational and policy insights. One hallmark of these models was detailed treatment of the computations needed to calculate historical embedded cost-of-service prices. As regulation changes, these models are revised and extended to capture new events. The reorganization of the electric industry to include competitive generation markets will eventually simplify this modeling task. Electricity prices will be determined by market forces based on the intersection of supply and demand, and most of the time generation prices will be equal to the marginal costs of the most expensive generator operating at that time. During periods of excess demand [1], prices will rise to ration the available supply among the buyers.

However, during the transition period there are good reasons to model both the old and the new regimes. Modeling allows the examination of both regimes under controlled 'laboratory-like' conditions before the actual transition takes place. Additionally, one major transition cost, the excess of book value over market value, commonly referred to as stranded assets, will be determined by the difference between the new market prices and the old, regulated prices. Scoping out the size of the stranded asset problem and testing various recovery mechanisms becomes a central area of interest. Therefore, there is much current interest in comparing prices under both systems and in studying how these price differences change as policies toward restructuring are modified. POEMS allows policy-makers and legislators to quantitatively assess the implications of deregulation on ratepayers, shareholders, bondholders, and taxpayers.

OnLocation, Inc., has incorporated the TRADELEC™ model into NEMS to assist the Department of Energy's Office of Economic, Electricity, and Natural Gas Analysis better study the transformation of the electric power industry and to provide insights into the functioning of electricity and energy markets as part of the economy in the restructured environment.

The heart of the TRADELEC™ model is market driven electricity trade over the existing electric transmission system. Electricity trade is solved for as a function of relative prices, transmission availability and a hurdle rate that is designed to reflect the additional costs of handling market trading. TRADELEC™ represents transmission interties at existing transfer interfaces based on data reported at the power control area (PCA) level. Current and future bottlenecks may limit trade flows among certain buyers and sellers when transmission capacity is reached. This would result in final regional price differences that exceed the cost of transmission and trading.

This trading function is critical in determining competitive prices for electric power and in measuring any efficiency gains from restructuring the electric industry. By explicitly solving trade relationships, the model allows insights into pricing patterns and the motivation for interregional trading.

Network interregional trade is solved to maximize the economic gains from trade by ordering the trades in descending order starting with the trade that contributes the largest efficiency gains first. Succeeding trades continue until available transmission opportunities or all the possible gains are exhausted. The primary economic and physical limits to trade are imposed via alternative scenarios of transmission fees, losses, transmission capacity, and hurdle rates. Thus, integrated interregional trade is modeled to operate in much the same fashion as a full fledged, time-block power auction could operate.

In the absence of transmission constraints, electricity prices nationwide would converge to a single value with local delivery prices varying only by differences in the cost of transmission (including line losses) and distribution services. However, the tendency in competitive markets toward a single price does not mean that there will be no market separation. Because transmission is neither unconstrained nor without cost, separable regional electricity markets are likely to be observed as model solutions evolve. Additional regional constraints, such as regional specific pollution abatement measures could further increase regional price differences even with fully competitive power markets.

[1] By definition, the demand for electricity cannot exceed supply; but situations where consumers may want more power than the system can deliver are possible. When this situation arises, demand must be cut back to the available supply. With cost-of-service regulation this is accomplished by using voltage reductions, rolling blackouts or some other administrative approach. In competitive markets, prices will rise until consumers reduce demand and/or producers increase supply until the two equate.

Model Description and Structural Assumptions

Demand/Load

Electricity demand information is drawn from the NEMS system by customer class and end-use or industrial type (e.g. commercial lighting or paper industry electricity use) at the census region level. Each of these end-uses or industries is assigned a distinct load shape. For weather sensitive demands, the load shapes vary by region as well. In each future year, the end-use load shapes are added together and then the loads are allocated to individual PCA's based on the historical proportion of sales (i.e., load) within each power control area in each larger region.

A unique aspect of the POEMS model, which it shares with the NEMS electricity sector, is the representation of the load duration curves with vertical, rather than horizontal, time blocks. For most applications, loads are represented by 2 segments within 6 daily time blocks within each of 6 seasons, although these can be varied by the user. Except for one peak segment, each segment within each season represents the average load in that time block.

Dispatch/Trade

TRADELEC™ is a network model of electricity dispatch, trade, capacity expansion and pricing (see Figure 2). The POEMS version of the model operates at the level of the power control area (PCA), representing approximately 114 regions (Figure 3). PCAs are represented as a series of nodes, connected by transmission interties whose capacities are specified based on transfer capabilities reported to FERC. There are over 650 transmission links in POEMS. New transmission additions are limited to maintenance and those associated with the construction of new generating assets. Within each PCA, supply resources are represented in considerable detail, including utility plants, exempt wholesale generators, traditional and non-traditional cogenerators, and firm power contracts. Although usually existing firm power wholesale contracts for generation or capacity are assumed unabrogated, a user option is available for canceling these contracts. Plant characteristics, such as capacity, heat rate, and forced and maintenance outage rates, are represented based on data in EIA filings and NERC GADS data.[2] TRADELEC™ incorporates financial, operational, and physical data representing virtually every significant operating electric utility in the USA and the transmission interties among them.

Each unit in the plant input file is combined with like units to form dispatchable groups. The process of combining units is flexible, but at a minimum, combined units serve the same demand region and are physically located in the same supply region, use the same fuels with the same type of prime mover and have the same in-service period. Dispatchable capacity groups also have similar heat rates and renewable groups have similar utilization patterns. Currently, there are over 6,000 plant groupings used in the model. There are 55 dispatchable plant groupings per PCA on average, with larger PCAs having as many as 350 plant groups. A merit order dispatch algorithm is initially employed to determine generation in each time segment prior to trade.

[2] NERC Generating Availability Data System

Figure 2: TRADELEC Electricity Market Module

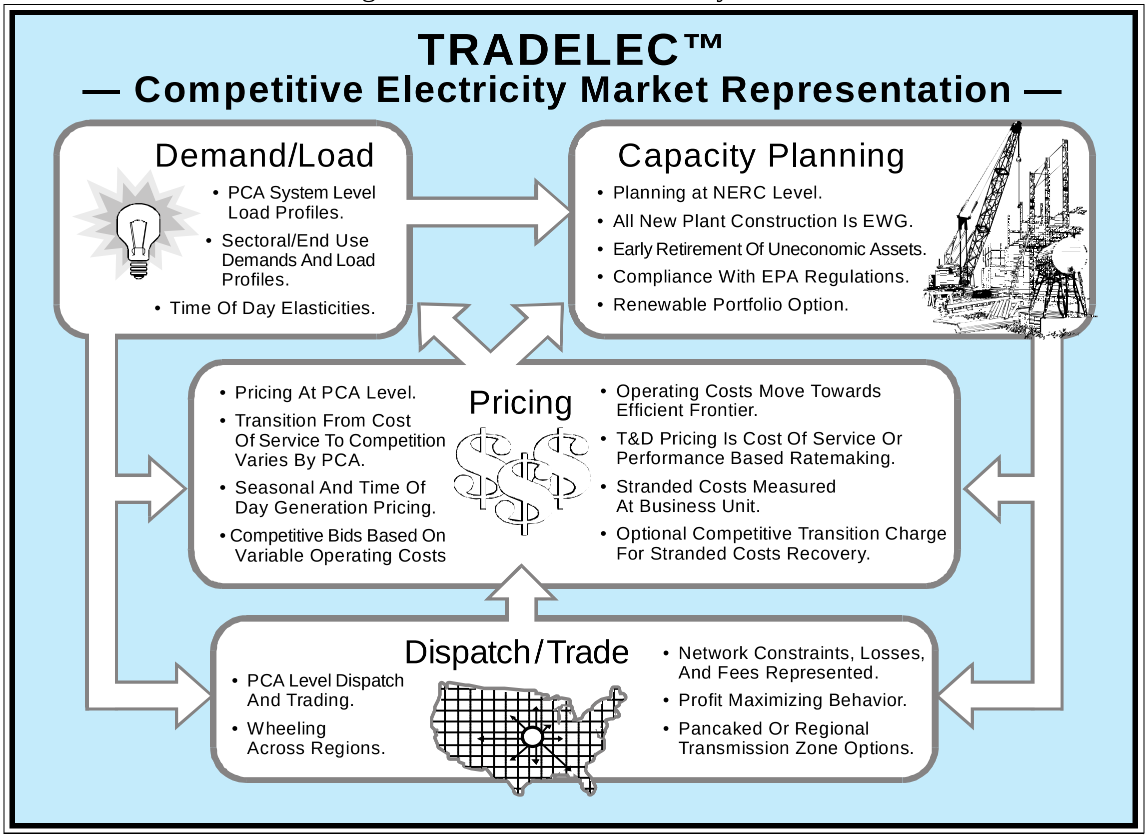
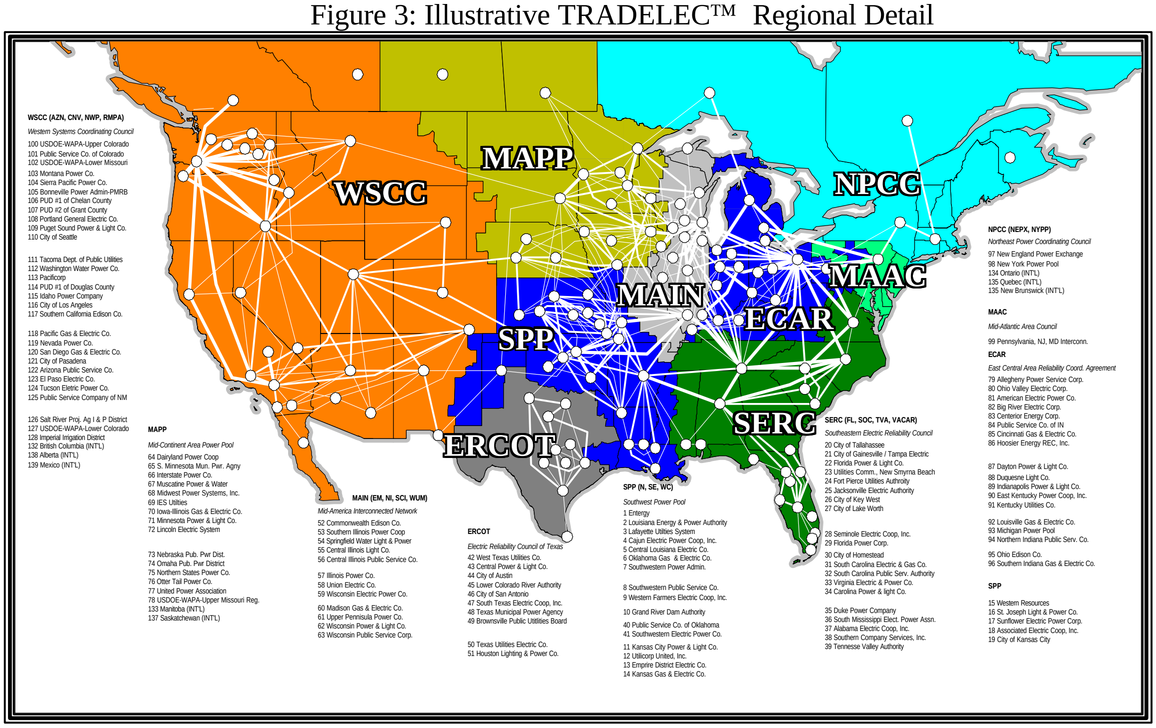


Figure 3: Illustrative TRADELEC™ Regional Detail



Transmission capacity is measured on a first contingency basis consistent with the established NERC rules. Transmission charges are calculated on approximations of straight-line, simultaneously available paths to project the volume and costs of electricity trade. Transmission costs are reflected through representation of transmission tariffs (which can be implemented on a PCA or regional level) and transmission losses (a non-linear, distance sensitive measure). Further, a user specified "hurdle level" is input to limit transactions to those that provide a specified minimum level economic gain. The hurdle rate can be adjusted to reflect reductions in potential inefficiencies and transactions costs as markets provide greater incentives to exploit profitable trades. The market simulation is conducted within each of the 72 time/season blocks modeled - maintaining the chronological simultaneity.

Capacity Planning

In addition to dispatching existing capacity and trading among regions, the need for new capacity additions is calculated. The capacity planning methodology is similar to that of the NEMS electricity sector except that it is assumed that no new capacity additions will be rate-based by utilities in a competitive market scenario. Rather, the construction of all new facilities is profit motivated based on anticipated demand growth and competitive cost conditions caused by capacity shortages. Because of the higher risk associated with an unregulated market, the cost of capital is assumed to be higher than historical values for the industry. In a cost-of-service case, all new capacity is assumed to be constructed by Exempt Wholesale Generators (EWGs) which sell under long-term contracts to utilities. Capacity planning occurs at the NERC regional level, and new plants are allocated to individual PCAs based on their relative prices, system loads, and shortfall of capacity (if any).

The choice of new technology selection for new capacity is the same as in the NEMS electricity sector. The expansion algorithm minimizes the expected cost of meeting anticipated future load. In order to reflect that there will be site specific differences in costs within a planning region, the model includes a logit-based sharing mechanism. In this way technologies that were slightly more expensive will receive some market share. The TRADELEC™ capacity planning module also includes a feature that allows goals for renewable builds to be specified exogenously.

One aspect of POEMS that distinguishes it from NEMS and other models is its explicit treatment of economic retirements. Retirements of existing capacity occur when plant operating costs cannot be recovered through market-based prices. For some plants, there are some "forced" retirements determined exogenously in addition to economic retirements. No nuclear plants are assumed to continue operating after the end of their 40-year operating licenses. In addition, some nuclear plants are assumed to retire sooner, based on an analysis performed by EIA for the AEO98 identifying plants that "are among the first generation of plants to come on line, and generally have high operating costs, or have not made equipment repairs … which are likely to be required for extended operation."[3]

The economic retirement decision for all generating plants is based on both short-term and long-term criteria. The short-term requirement is that plants can cover their "going-forward" costs, which includes all O&M costs and annual capital additions, by the revenue they receive through the marginal cost (MCP) in the wholesale market. If a plant cannot cover these costs, it becomes a candidate for early retirement. The second consideration is the cost of building new generating capacity. In the capacity planning module, all existing units must pay their going-forward costs if the capacity is to be used over the full planning horizon. Thus the planning module has the opportunity to economically retire any or all of the existing

[3] EIA, Assumptions to the Annual Energy Outlook 1998

units and instead build new capacity. If the planning module does decide to economically retire a unit and this same unit did not cover its variable costs in the last forecast year, it is retired. A plant must be uneconomic in both the short-term and long-term to be retired.

Pricing

TRADELEC™ can represent either cost-of-service or competitive pricing[4] in retail markets. The cost-of-service pricing reflects financial information aggregated from filings made by investor-owned, public, federal, and cooperatively-owned utilities.[5] Competitive rates are based on unbundled time-specific generation prices, and transmission and distribution prices. These latter are assumed to remain cost-of-service or can be set to reflect Performance Based Ratemaking, where an incentive is included to reduce costs.

Another distinguishing feature of the POEMS model is its flexible internal treatment of stranded costs in its pricing through the transition period. The competitive generation price is composed of the marginal cost, ancillary charges, a renewable portfolio standard (RPS) premium (if applicable), and stranded costs: decommissioning, regulatory assets, and generating assets. Marginal generation prices are set in each power control area (PCA) based on the marginal cost or bid price of the last unit running in each of 72 time slices. The last unit could be native to the PCA or determined through trade with other PCA's. The competitive bid price for each unit is assumed to be its marginal cost in accord with the standard characterization of perfectly competitive markets. The marginal costs are the sum of the fuel costs and the variable portion of operating and maintenance (O&M) costs.

The historical distinction between fixed and variable O&M costs is quite arbitrary, thus the POEMS initially puts all O&M costs into a fixed O&M account and allows the user to determine how much of the fixed costs should be considered variable. In addition, historical O&M costs are expected to be reduced over time due to the pressures of competition. The POEMS includes a feature that allows the user to specify O&M targets by plant type, and percentage cost reduction by plant type and year. (Competitive pressures are also expected to spill over into the regulated segment of the industry. The POEMS also allows the user to specify transmission and distribution productivity improvements). Competition is also expected to result in heat rate improvements, which affect the generation price. POEMS includes a feature that allows the user to specify target heat rates by plant type and percentage improvements by plant type and year.

Ancillary charges are assumed to be paid by Independent System Operators (ISOs) in competitive scenarios to generators in order to maintain system reliability. The total expenditures are determined by the amount of revenue that owners of new peaking capacity need in addition to the market bid price in order to cover all their costs (including fixed costs). Because of reserve margin requirements, some plants will be constructed that will not operate very much, if at all, but are needed for reliability. This additional revenue is then paid on a dollar per kilowatt-year basis to all combustion turbines and combined cycle plants in the region. Because the markets are competitive, the ISO's must pay all units the same amount and cannot discriminate between new and existing plants. The combustion turbines and combined cycle plants are the only ones that receive the payment because they can most readily be called on for quick startup reserve purposes.

[4] While TRADELEC™ can estimate competitive prices under alternative approaches, the competitive pricing in POEMS is implemented as a second-price auction.
[5] The information is drawn from federal filings including FERC Form 1, EIA Form 412 and RUS Forms 7 and 12.

The renewable portfolio standard (RPS) is a feature that can be imposed on a competitive scenario as a minimum share of generation that must be met by non-hydro renewable resources. These include wind, biomass, solar thermal, solar PV, and geothermal. Because the renewable credits can be traded, the RPS is a national goal. Assuming the effect of a nationwide auction, the most expensive unit needed is the one that sets the price. In this case the price includes capital cost recovery. The total cost of the RPS equals the marginal renewable cost on a dollar per kilowatt-hour basis times the total renewable generation in each year. It is assumed to be charged equally to all customers in all regions of the country.

Stranded generation assets are those that have remaining capital costs that cannot be recovered through competitive prices. The stranded costs are computed at the company level, where each company's assets with below market costs offset those that are above market. In the POEMS Competitive case, recovery of these costs is set by the user by specifying the percentage of recovery, recovery period, discount rate, and start year of recovery. In addition, the user also sets the allocation method for recovery by customer class.

The relationship between competitive and cost-of-service prices will not be uniform across PCAs. Indeed, it is possible that competitive prices (on average) will exceed cost-of-service prices in areas with low embedded costs. The relationship between competitive and cost-of-service prices is a primary focus of attention in the restructuring debate, and the likely variation in this relationship across PCAs highlights the value of modeling at a disaggregated level. Disaggregation also allows for an evaluation of a piecemeal implementation of restructuring, which is of considerable interest to some policymakers. Piecemeal implementation allows competition to be initiated in different years for individual PCAs.

Additional Structural Assumptions

By its structure and its use for policy analysis, POEMS contains either implicitly or explicitly many assumptions of how a competitive market for electricity will evolve. The most fundamental assumption is that all activities will be economically motivated and be driven by profit maximizing or cost minimizing behavior. In addition to the structural assumptions, there are several parameters that can be specified by the user in order to represent alternative scenarios of restructuring. The following table includes a list of both the structural and scenario-type assumptions in POEMS.

POEMS Assumptions

Basic Structure:

· Initial generation, transmission and distribution assets reflect best available data
· Regional representation includes 114 Power Control Areas (PCAs) and 680 transmission links
· New transmission additions are limited to maintenance and those associated with the construction of new generating units
· Power dispatch and trading occurs for 2 segments within 6 daily time blocks in each of 6 seasons of the year (total of 72)
· Transmission and distribution continue to be regulated services, but can be incentive driven
· Demand levels and load shapes are dynamic modifications of historical record
· Existing legislation remains in place, for example, the Clean Air Act
· Macroeconomic and fuel price forecasts is consistent with EIA's Annual Energy Outlook

Competitive Scenario:

· All activities are economically motivated; driven by profit maximizing/cost minimizing behavior
· All generation, transmission & distribution activities are unbundled
· Electricity prices are based on the value of power plus transmission, trading and distribution costs
· Generators have no market power
· All consumers have direct market access and full contemporaneous information
· Transmission charges are calculated by applying a FERC Order 888 type formula
· Inter-regional trading clears markets in each time block, constrained by limited transmission capacity
· New generating capacity additions and retirements are profit motivated
· No new generation capacity is rate-based

Scenario Options (User Specified):

· Consumer price approach
  · PCA-level average embedded cost or market-area value priced
  · continuing historical cross class price subsidies or same time-specific generation price to all classes of customers
  · transmission and distribution pricing cost-of-service or incentive driven
· Existing long-term wholesale contracts for generation or capacity usually assumed unabrogated, but can be canceled
· Competitive rates can be phased-in both over time and geographically
· Alternative user-specified competitive transition charges (CTC) for stranded cost recovery
· Alternative formulas for transmission charges
· Renewable portfolio standard option
· Additional optional settings include but are not limited to changing the fraction of non-fuel operating costs that are considered to be variable; increasing the risk premium on interest rates; imposing a competitive transaction hurdle charge on trades; and reducing O&M costs and heat rates to represent heightened competitive pressures

Model Inputs and Data Assumptions

TRADELEC™ inputs include some that are completely exogenous to the model, and some that are passed from other NEMS models. Data passed from other NEMS models include sectoral electricity demands, fuel prices, and macroeconomic data. Exogenous inputs include such things as: power plant capacity data, technology costs and performance data, transmission capacity, electric power import assumptions, and financial assumptions. The following sections describe the sources of these input data and a sample of the initial settings for the POEMS.

Demand/Macroeconomic

The sectoral demand forecasts are derived from NEMS demand models. The POEMS currently uses the AEO97 demands models. However, because demand is determined endogenously and electric sector price and fuel demand are different, end-use demand does not match that published by the EIA.

End-use load shapes are based on NERC load data. System load shapes are derived from FERC Form 714/715 filings for each PCA. Companies within each PCA have been defined by OnLocation largely based on FERC filings. The EIA AEO97 mid-case assumes 2.1% growth in GDP between 1995 to 2010.

AEO97 mid-case demand forecasts were as follows:

Sales (billion kWh)	1995	2000	2005	2010
Residential	1043	1137	1214	1307
Commercial	946	1024	1089	1147
Industrial	1013	1122	1218	1289
Transportation	6	7	24	41
Total	3008	3290	3545	3784

Supply

Fuel Prices

Fuel prices are supplied by the NEMS fuel supply modules. The POEMS currently uses the AEO97 fuel supply models. Again, because fuel prices and demand are determined endogenously, they will differ from that published by EIA.

AEO97 resource fuel prices were as follows:

Fuel prices (1995 dollars per unit)	1995	2000	2005	2010
World Oil Price (dollars per barrel)	17.26	18.20	19.72	20.41
Gas Wellhead Price (dollars per Mcf)	1.61	1.82	1.94	2.01
Coal Minemouth Price (dollars per ton)	18.83	18.38	17.47	16.92

Average delivered fuel prices to electric generators were as follows:

Delivered Prices (1995 Dollars per Million Btu)	1995	2000	2005	2010
Distillate Oil	3.94	4.52	4.77	4.92
Residual Oil	2.62	2.81	2.97	3.15
Natural Gas	2.01	2.19	2.28	2.32
Steam Coal	1.32	1.29	1.24	1.20

Generation Capacity assumptions

Production capacity assumptions regarding utility plants, exempt wholesale generators, and nontraditional cogenerators are derived from EIA and FERC filings (Form EIA-860, Form EIA-867, Form EIA-759, and Form EIA-767). The input assumptions include 1995 capacity and announced retirements and additions. Projected capacity will reflect these inputs, as well as endogenously determined additions and economic retirements.

Existing and Exogenously Planned Capacity (GW)	1995	2000	2005	2010
Winter	755	759	752	745
Summer	743	747	740	734

Firm purchase power contracts are derived from EIA Form 411 filings. These include existing wholesale contracts between utilities.

Firm Power Contracts (GW)	1995	2000	2005	2010
Winter	9.5	8.7	6.5	4.3
Summer	11.1	10.1	7.6	5.1

New cogeneration is added in a linear relationship to projected increases in industrial steam demand, and passed from the demand models. While the POEMS will produce a slightly different result when run with the demand modules, AEO97 mid-case assumptions regarding cogeneration are as follows:

	1995	2000	2005	2010
Total Cogeneration (GW)	45.1	47.6	50.2	52.3

Transmission Capacity assumptions

Transmission capacity is measured on a first contingency basis for each PCA from FERC 714 filings. Transmission capacity available for export from (and import into) each PCA is constrained to the PCA's maximum transmission path, and subject to line losses, transmission fees, and hurdle rates.

Because it does not make sense to sum up transmission capacity across PCAs, a national summary is not provided here.

Technology costs and performance assumptions

Technology cost and performance data for new plants is derived largely from EIA's AEO98 mid-case and NERC GADS data. The following table provides a brief summary of initial plant cost and performance settings. Capital costs are adjusted in the model using NEMS assumptions about uncertainty as reflected in technological optimism and learning factors. In addition, there are user options in POEMS which allow adjustments by technology and over time to O&M costs and heat rates of existing plants.

	Capital Costs (Nth of a Kind) ($1996/kW)	O&M Costs ($1996/kW)	Heat Rates (Nth of a kind) (Btu/kWh)	Availability
Pulverized Coal	1,079	15.9	9,087	.85
Advanced Coal	1,206	15.9	7,308	.85
Oil/Gas Steam	991	8.0	9,500	.85
Combined cycle - Conventional	440	5.3	7,000	.91
Combined cycle - Advanced	400	5.3	6,350	.91
Combustion Turbine - Conventional	325	2.7	10,600	.92
Combustion Turbine - Advanced	320	2.7	8,000	.92
Fuel Cell	1,440	5.3	5,361	.87
Nuclear	1,550	55.0	10,400	.85
Biomass	1,476	66.3	8,224	.80
Geothermal	2,025	95.7	N/A	.80
Municipal Solid Waste	5,289	0.0	16,000	.78
Solar Thermal	1,910	46.0	N/A	N/A
Solar Photovoltaic	3,185	9.7	N/A	N/A
Wind	965	25.6	N/A	N/A

Reserve margins

The need for reserve margins is related to the availability of each power control area's generation resources and the ability to trade with others. Over the last decade, plants have been getting more reliable in part due to the pressures of the wholesale competition. Both forced and scheduled outages have been reduced. Trading has also increased, especially after FERC Order 888 required transmission access. In addition there has been a growing use of interruptible load contracts, which have been factored into reserve margins. In order to reflect these continuing changes, POEMS uses a reserve margin of 8% for all regions of the country except Florida, which uses a 4% reserve margin.

Financial Assumptions

Cost of service pricing is based on 1995 FERC Form 1, EIA Form-412, and REA Forms 7 and 12 filings.

Discount rate/Costs of Capital: A number of different discount rates and costs-of-capital are at work in the model structure.

For the reference scenario ---

- Utility cost of capital and capital structure – applies to both the annual revenue requirement calculations (for all segments, that is to say, the generation, transmission and distribution functional segments) and to the expansion planning decision regarding the discount rate applied to calculate the present value of meeting the demand.
- EWG cost of capital and capital structure – applies to the annualized costs associated with each generation technology's investment requirement and the resultant annuity added to the fixed O&M costs in the "purchased" power portion of the revenue requirements associated with new builds. All new, unplanned builds are assumed to be Exempt Wholesale Generators (EWGs).

For the competitive scenario ---

- Utility cost of capital and capital structure – applies to the annual revenue requirement calculations for the transmission and distribution functional segments only.
- EWG cost of capital and capital structure – applied the same as in the reference case, except the assumed values are raised to reflect the greater risks assumed in the competitive environment; also used in the expansion planning decision.

Case		Utility	EWG
Reference	Debt Fraction	0.49 - .66**	0.65
Reference	Return on Debt	0.10	0.10
Reference	Return on Equity	0.10 - 0.14*	0.18
Competitive	Debt Fraction	0.49 - .66**	0.60
Competitive	Return on Debt	0.10	0.10
Competitive	Return on Equity	0.10 - 0.14*	0.20

* Utility Return on Equity is a function of the national yield on new AA bonds and some additional basis points, and varies by year.
** Utility Debt Fraction varies by region.

Transmission charges

Wheeling charges are set to some percentage (generally 50 to 80 percent) of the average FERC Order #888 stage one pro forma point-to-point tariff. A summary of wheeling fees by region is provided in Attachment A.

Attachment A
Regional Model Inputs

Annual Peaks in 1995

	Region name	Peak (mw)
1	ECAR	83,375
2	ERCOT	43,132
3	MAAC	45,949
4	MAIN	42,175
5	MAPP	25,096
6	NEPX	19,284
7	NYPP	26,656
8	FL	28,335
9	SERC	100,574
10	SPP/N	13,295
11	SPP/SE	23,191
12	SPP/WC	17,338
13	WSCC/AZN	11,947
14	WSCC/CNV	44,496
15	WSCC/NWP	35,980
16	WSCC/RMPA	6,226

Winter Planned and Existing Capacity (Mw)

Region name	1995	2000	2005	2010
ECAR	109,938	111,221	111,221	110,441
ERCOT	55,178	56,279	56,507	58,104
MAAC	60,045	60,024	60,024	57,060
MAIN	52,905	52,921	49,755	47,150
MAPP	33,780	34,052	33,107	33,107
NEPX	27,080	25,632	24,315	23,793
NYPP	37,085	37,026	36,257	34,876
FL	37,794	38,319	38,319	38,319
SERC	125,478	126,658	125,593	125,593
SPP/N	17,564	17,570	17,570	17,570
SPP/SE	32,448	32,448	32,448	32,448
SPP/WC	24,366	24,366	24,366	24,366
WSCC/AZN	20,081	20,511	20,511	20,511
WSCC/CNV	56,717	56,787	56,807	56,807
WSCC/NWP	51,331	52,137	52,125	52,125
WSCC/RMPA	11,140	11,268	11,268	11,268
Total U.S.	754,927	759,222	752,201	745,551

Summer Planned and Existing Capacity (Mw)

Region name	1995	2000	2005	2010
ECAR	108,083	109,366	109,366	108,611
ERCOT	54,951	56,051	56,280	57,876
MAAC	57,632	57,629	57,629	54,715
MAIN	51,876	51,892	48,809	46,203
MAPP	32,814	33,087	32,158	32,158
NEPX	26,420	25,005	23,699	23,203
NYPP	35,880	35,834	35,091	33,710
FL	36,351	36,877	36,877	36,877
SERC	123,877	125,057	123,992	123,992
SPP/N	17,330	17,336	17,336	17,336
SPP/SE	32,442	32,442	32,442	32,442
SPP/WC	24,219	24,219	24,219	24,219
WSCC/AZN	19,897	20,327	20,327	20,327
WSCC/CNV	56,440	56,510	56,529	56,529
WSCC/NWP	51,431	52,234	52,224	52,224
WSCC/RMPA	11,037	11,165	11,165	11,165
Total U.S.	742,677	747,031	740,148	733,598

Winter Contracts (Mw)

region name	1995	2000	2005	2010
ECAR	807	-12	-90	-60
ERCOT		-9		0
MAAC	-409	-560		0
MAIN	427	154	110	73
MAPP	-508	-259	-266	-177
NEPX	-1,074	-1,040	-383	-255
NYPP	437	529	389	259
SERC	-910	42	205	137
SPP/N	-439	-121	-5	-3
SPP/SE	447	168	24	16
SPP/WC			-5	-3
WSCC/AZN	-3,450	-3,136	-2,352	-1,568
WSCC/CNV	-3,113	-2,830	-2,123	-1,415
WSCC/NWP	-3,287	-2,988	-2,241	-1,494
WSCC/RMPA	317	288	216	144
Total U.S.	-9,533	-8,666	-6,500	-4,333

Summer Contracts (Mw)

region name	1995	2000	2005	2010
ECAR	1,463	490	141	94
MAAC	-374	-154	0	0
MAIN	326	126	262	175
MAPP	-629	-1,162	-947	-631
NEPX	-643	-500	-380	-253
NYPP	-262	-622	-167	-111
SERC	-1,310	-322	-68	-45
SPP/N	-407	-95	21	14
SPP/SE	393	168	24	16
SPP/WC				-40
WSCC/AZN	-5,366	-4,878	-3,658	-2,439
WSCC/CNV	-5,331	-4,846	-3,635	-2,423
WSCC/NWP	-510	-464	-348	-232
WSCC/RMPA	73	66	50	33
Total U.S.	-11,134	-10,122	-7,592	-5,061

Wheeling Charges ($/MWh)	
Region	Dollars Per MWh (Discounted 50%)
ECAR	2.66
ERCOT	1.89
MAAC	2.39
MAIN	1.88
MAPP	3.11
NEPX	1.69
NYPP	3.81
FL	2.13
SERC	2.01
SPP/N	2.07
SPP/SE	2.76
SPP/WC	2.29
WSCC/AZN	4.27
WSCC/CNV	3.32
WSCC/NWP	4.25
WSCC/RMPA	2.54